Attachment C

KANSAS DEPARTMENT OF HEALTH AND ENVIRONMENT'S EVALUATION OF ABENGOA BIOENERGY BIOMASS OF KANSAS, LLC PROPOSED GHG BACT OPTIONS

I. Greenhouse Gas Emission Units Subject to Best Available Control Technology

The following are the greenhouse gas (GHG) best available control technology (BACT) analyses prepared and submitted by the Abengoa Bioenergy Biomass of Kansas (ABBK) to the Kansas Department of Health and Environment (KDHE) for evaluation. The following GHG BACT analyses determine the most effective control of GHG emissions from the proposed biomass-to-ethanol and biomass-to-energy production facility.

For more details, please refer to the following document prepared by ABBK: ***Prevention of Significant Deterioration, Air Quality Construction Permit Application Supplement, Greenhouse Gases Best Available Control Technology Analysis*** **dated May, 2011**.

The proposed facility will consist of the GHG emissions units listed in Table C-1.

Table C-1. Summary of Emission Units Subject to GHG BACT

Stack ID	Equipment/Process	Proposed BACT Emission Limit(s)	BACT Device(s) or Operational Limitation(s)
EP-08000	HV Circuit Breaker	4.9 short ton CO_2e/yr	State-of-the-art enclosed-pressure SF_6 circuit breaker with leak detection to maintain fugitive SF_6 emissions < 0.5% per yr (by weight); Leak Detection and Repair (LDAR) and density monitor alarm set to 4 psi drop.
EP-20001	Biomass-Fired Stoker Boiler	0.34 lb CO_2e/lb steam produced, averaged over 30 day rolling periods including periods of startup, shut-down or malfunction	Restriction of the fuel type to biomass that is otherwise considered to have low to no economic value or benefit, and/or is a lower impacting crops; and lower GHG-emitting processes and practices through an energy efficient design, incorporating cogeneration, process integration, combustion of co-products, heat recovery and operational and maintenance monitoring.

Table C-1. Summary of Emission Units Subject to GHG BACT

Stack ID	Equipment/Process	Proposed BACT Emission Limit(s)	BACT Device(s) or Operational Limitation(s)
EP-18185	EH Fermentation CO_2 Scrubber	5.89 lb CO_2e/gal anhydrous ethanol produced, averaged over 30 day rolling periods including periods of startup, shut-down or malfunction	Monitoring enzymatic hydrolysis process efficiency, incorporating monitoring CO_2 production during fermentation, energy efficient heat integration, water recycling, and co-product production.
EP-09001	Biogas Flare	20,166 short tons CO_2e/yr during any twelve (12) consecutive month period	Restriction of the fuel type to primarily biogas and pipeline-grade natural gas in the pilot; and to use the most efficient flare that can perform to the specification required by the facility's process.
EP-06001	Firewater Pump Engine	24.0 tons CO_2e/yr during any twelve (12) consecutive month period	Fuel-efficient NFPA-20 certified firewater pump engine (20.3±5% gal/hr fuel consumption limit for a 460 Hp engine with a rated speed of 1760 rpm and an EPA Tier 3 emission rating).

II. <u>High Voltage Circuit Breaker Equipment Leaks GHG BACT Analysis</u>

A. Source Description

One (1) high voltage circuit breaker (EP-08000), rated at 125 kilovolts (kV), will be utilized at the facility. The circuit breaker will use 82 pounds of a sulfur hexafluoride (SF_6) dielectric in an enclosed-pressure system. The SF_6 has become the predominant insulator and arc quenching substance in circuit breakers today because of its superior capabilities. The SF_6's global warming potential (GWP) over a 100-year period that is 23,900 times greater than CO_2.

B. Identify Available Control Options

The following control options have been identified and considered in determining BACT:

1. Use of state-of-the-art SF_6 technology with leak detection (baseline);

2. Use of a non-SF_6 dielectric oil or compressed air/air blast;

3. Use of an emerging technology that is comparable to the properties of SF_6 but without the drawbacks of dielectric oil or air blast; and

4. Development and implementation of a Leak Detection and Repair (LDAR) program.

C. Eliminate Technically Infeasible Control Options

The use of an emerging technology to replace SF_6 was eliminated as a control option because it is technically infeasible. According to ABBK's BACT analysis, research and development efforts have focused on finding substitutes for SF_6 that have comparable insulating and arc quenching properties in high-voltage applications. While some progress has reportedly been made using mixtures of SF_6 and other inert gases (e.g., nitrogen or helium) in lower-voltage applications, most studies have concluded, "that there is no replacement gas immediately available to use as an SF_6 substitute" for high-voltage applications. According to the most recent report released by the EPA SF_6 Partnership, "no clear alternative exists for this gas that is used extensively in circuit breakers, gas-insulated substations, and switch gear, due to its inertness and dielectric properties." Therefore, the alternative to use an emerging technology to replace SF_6 was determined to be technically infeasible.

The use of dielectric oil or compressed air (air blast) circuit breakers were historically used in high-voltage installations prior to the development of SF_6 breakers. Thus, this option is technically feasible.

The use state-of-the-art SF_6 technology with leak detection to limit fugitive emissions is technically feasible and is the baseline control option. In comparison to older SF_6 circuit breakers, modern breakers are designed as a totally enclosed-pressure system with far lower potential for SF_6 emissions. The best modern equipment can be guaranteed to leak at a rate of no more than 0.5% per year by weight. In addition, the effectiveness of leak-tight closed systems can be enhanced by equipping them with a density alarm that provides a warning when SF_6 (by weight) has leaked from the breaker.

D. Rank Technically Feasible Control Options

Table C-2 presents the ranked technically feasible control options.

Table C-2. Ranked Control Options for High Voltage Circuit Breaker Equipment Leaks

Rank	Control Technology	Emission Rate (short tons CO_2e/year)	Emissions Reduction (short tons CO_2e/year)
1	Oil/air-blast circuit breaker	0	4.9
2	State-of-the-art enclosed-pressure SF_6 circuit breaker	4.9	N/A
3	Leak Detection and Repair (LDAR)	N/A	N/A

Note: Implementation of the LDAR program will not generate emissions, nor will it control emissions beyond the baseline. The LDAR program is used to monitor equipment leaks for repair.

E. Evaluate Technically Feasible Control Options

Considering the environmental aspect, according to ABBK's BACT analysis, the oil/air-blast circuit breakers option would require additional land to be devoted to the facility's design, would generate additional noise, and would increase the risks of accidental releases of dielectric fluid and/or associated fires. By contrast, according to the National Institute for Standards and Technology, SF_6 "offers significant savings in land use, is aesthetically acceptable, has relatively low radio and audible noise emissions, and enables substations to be installed in populated areas close to the loads." Therefore, oil/air-blast breakers do not surpass the choice of SF_6 breakers because of their adverse environmental impacts. Further, the EPA has recognized SF_6 as the preferred dielectric choice for circuit breakers, gas-insulated substations, and other switchgear used in the transmission system to manage the high voltages and is working with the industry through the SF_6 Emission Reduction Partnership to reduce GHG emissions via cost-effective technologies and practices.

When economics, energy, environmental are included, the most effective control technology that is technically feasible is the use state-of-the-art enclosed-pressure SF_6 circuit breakers. According to information from circuit breaker manufacturers, this equipment can be guaranteed to achieve a leak rate of 0.5% by year by weight or less. This leak rate meets the current maximum leak rate standard established by the IEC. This leak rate performance can be further enhanced by an alarm system to alert operators to potential leak problems as soon as they occur.

An LDAR program is technically feasible control option for this equipment. The LDAR program is used to monitor equipment leaks for repair.

F. Establish BACT

Based on this top-down analysis, ABBK proposes that GHG BACT for the onsite circuit breaker consist of the following:

1. State-of-the-art enclosed-pressure SF_6 circuit breaker with a guaranteed leak rate of 0.5% by weight or less by year;

2. Density monitor alarm system; and

3. Develop and implement a written LDAR program.

The ABBK facility will require one (1) breaker using 82 lbs of SF6. At a leak rate of 0.5%, annual SF6 emissions would be a maximum of 0.41 pounds per year, which would equal 4.9 short tons CO2e per year.

G. BACT Compliance

Fugitive SF_6 emissions shall be calculated by measuring "top-ups", i.e., the replacement of lost SF_6 with new product. The amount of SF_6 that has leaked and entered the atmosphere is the amount that has to be topped up to maintain a full SF_6 level. Therefore, no direct monitoring of SF_6 fugitive emissions will be required. In place of direct monitoring, a surrogate monitoring process through measuring the amount of SF_6 lost and using a conversion factor to calculate daily SF_6 fugitive emissions in terms of CO_2e shall be implemented.

For every replacement event of lost SF_6 with new product, ABBK shall record the date and quantity of SF_6 lost in pounds, and time period in days since the previous addition of SF_6. The recorded data shall be converted to pounds CO_2e per day.

ABBK shall install a density monitor alarm system to alert controllers when a circuit breaker loses SF_6. This alarm shall function as an early leak detector that will bring potential fugitive SF6 emissions problems to light before a substantial portion of the SF_6 escapes. In the event of an alarm, ABBK shall investigate the event and take any necessary corrective action to address any problems.

ABBK shall provide construction specifications, operation and maintenance records, and other record keeping documents to KDHE upon request to demonstrate compliance with BACT.

III. Cogeneration Biomass-fired Stoker Boiler GHG BACT Analysis

A. Source Description

The cogeneration plant will employ one (1) water-cooled vibrating grate (stoker) boiler. The boiler will be capable of producing 325,000 pounds per hour of 920 pound-force per square inch gauge (psig) /750 °F steam. The high pressure steam supplies a single condensing-extraction steam turbine generator nominally rated at 22 Megawatts of electricity (MWe). Electrical power will be supplied only to the facility. Power sales to the grid are not foreseen at this time.

Enzymatic hydrolysis process steam is extracted from the turbine at a lower pressure from extraction ports. Boiler feedwater preheater steam and deaeration steam is also extracted from the turbine from extraction ports. Exhaust steam is condensed under vacuum against cooling water in the cooling water tower. The stoker boiler's maximum design heat input is 500 million British thermal units per hour (MMBtu/hr). The stoker boiler is capable of burning a combination of raw biomass (consisting of corn stover, wheat straw, milo (sorghum) stubble, corn stover, switchgrass, and other opportunity feedstocks that are available), enzymatic hydrolysis residuals (including lignin-rich stillage cake and thin stillage syrup), particles collected during biomass grinding, NCG vent streams, wastewater treatment sludge and biogas. Natural gas will be used during start-up periods as required per manufacturer recommendations. The stoker boiler will also be capable of firing on natural gas during normal operations as needed at a limited capacity, as well as firing on a combination of natural gas, liquid fuel (i.e. enzymatic hydrolysis thin stillage syrup) and biogas in the event of a solid fuel failure. The cogeneration process will utilize up to 812 dry tons/day of fuel feedstock.

The biomass-fired stoker boiler is the main source of anthropogenic GHG emissions (CO_2, CH_4, and N_2O) at the facility. The total CO_2-based emissions from the boiler are 481,652 tons/yr of CO_2e. This amount of CO_2e-based emissions is over 81% of the total facility-wide CO_2e-based emissions.

B. Identify Available Control Options

The following control options have been identified and considered in determining BACT:

1. Use of low-carbon and carbon neutral fuels;

    a. Corn stover
    b. Wheat straw
    c. Milo stubble
    d. Wood chips/wood residues
    e. Switchgrass
    f. Other opporunity agricultural residues and energy crops

g. Enzymatic hydrolysis residuals (including lignin-rich / lignin-lean stillage cake and thin stillage syrup)

2. Use of lower GHG-emitting processes/practices/design;

   a. Cogeneration
   b. Process integration and combustion of process co-products
   c. Heat recovery
   d. Boiler operational monitoring
   e. Boiler maintenance

3. Carbon capture and storage ("CCS", also referred to as "carbon capture and sequestration");

4. Carbon capture for beneficial uses; and

5. Combination of These Control Options.

   There are two (2) broad strategies for reducing GHG emissions from the boiler at the proposed facility. The first is to minimize the production of GHG through the use of low-carbon and carbon neutral fuels and through the use of lower GHG-emitting processes/practices/design. As discussed in detail in the Environmental Impact Statement (EIS) by the Department of Energy (DOE), the proposed facility will provide a net reduction in GHG emissions because of the fuel selected and the long-term land use benefits. Additionally, the use of lower GHG-emitting processes/practices/design requires less fuel for process heat, which directly impacts the amount of GHG produced. Establishing an aggressive basis for energy recovery and process efficiency will reduce GHG production. The implementation of the use of low-carbon and carbon neutral fuels and the use of lower GHG-emitting processes/practices/design are an integral part of the facility's design and are considered the baseline for this BACT analysis.

   The second strategy for reducing GHG emissions is carbon capture and storage ("CCS", also referred to as "carbon capture and sequestration") or carbon capture for beneficial uses. These control options are evaluated in this BACT analysis as additional control options in addition to the baseline control options that are already included in the facility's design.

C. Eliminate Technically Infeasible Control Options

Three main options identified for control of CO_2 emissions from the boiler are: 1) Low-carbon and carbon neutral fuels; 2) Lower GHG-emitting processes/practices/design; and 3) CCS and/or carbon capture for beneficial uses. Table C-3 summarizes the technical feasibility/infeasibility determination for all control options discussed in this section.

Table C-3. Technical Feasibility/Infeasibility Determination Summary

Potentially Available Control Option	Determination Result	Determination Reason
Fuel Type Restriction to Low-Carbon and Carbon Neutral Fuels	Technically Feasible	Inherent part of the facility's design, and considered a baseline control option.
Lower GHG-Emitting Processes/Practices/Design	Technically Feasible	Inherent part of the facility's design, and considered a baseline control option.
Carbon Capture Using Pre-combustion Capture	Technically Infeasible	Technology would redefine the project.
Carbon Capture Using Oxygen-fired Combustion	Technically Infeasible	Technology would redefine the project.
Carbon Capture Using Post-Combustion Capture	Technically Feasible	Chemical absorption has been the most widely used method of commercial CO_2 capture and is the primary CO_2 capture technology further analyzed.
Carbon Transportation	Technically Feasible	Technical issues can be addressed through modern pipeline construction and maintenance practices.
Carbon Storage through Geologic Sequestration	Technically Feasible	In Kansas, geologic sequestration of CO_2 may be possible in all five of the geologic formations: deep saline aquifers, coal seams, oil and natural gas reservoirs, oil- and gas-rich organic shales, and basalt
Carbon Storage through Terrestrial Sequestration	Technically Feasible	Inherent part of the facility's design, and considered a baseline control option.
Carbon Beneficial Uses	Technically Feasible	The many different technologies being investigated for the beneficial use of CO_2 vary widely in their stages of development, from those being tested at the bench-scale, to technologies that are close to commercialization.
Combination of these Control Options	Technically Feasible	See reasons above.

1. Fuel Type Restriction (Low-Carbon and Carbon Neutral Fuels)

Numerous fuels are available for use in the boiler based on the proposed boiler design. The primary fuel initially to be used is corn stover. Other opportunity feedstocks that may be used if available include wheat straw, milo stubble and waste wood chips. Mixed warm season grasses such as switchgrass is a long-term feedstock that the facility plans to transition to as it's primarily fuel. By the year 2018, ABBK anticipates approximately 240,000 acres (970 square kilometers) of mixed warm season grasses will supply approximately 1,900 dry tons (1,700 metric tons) per day, which equates to 75% of the feedstock demand.

Other process residuals and by-products that are produced at the facility such as enzymatic hydrolysis residuals (including lignin-rich/lignin-lean stillage cake and thin stillage syrup), particles collected during biomass grinding, non-condensable gas (NCG) vent streams, and wastewater treatment sludge and biogas will also be combusted in the boiler. Natural gas will be used during start-up periods as required per manufacturer's recommendations.

Table C-4 presents the primary proposed fuel types and approximate carbon content for each. Due to the facility's design, only the primary fuels were included in Table C-4. The boiler will not be able to burn the other process residuals and by-products individually and these supplemental fuels are fed to the boiler to either: 1) increase the overall efficiency of the facility's processes; or 2) combust by-products that would otherwise require off-site disposal. Because the primary fuel(s) will be blended during combustion with supplemental fuels, the nominal fuel blend and worst-case fuel blends were reviewed.

Table C-4. Primary Proposed Fuel Types and Approximate Carbon Content

Feedstock	**Ultimate Analysis Carbon Content (wt. % dry basis)**
Corn Stover	40.7%
Wheat Straw	46.6% ±2.8
Milo Stubble	46.1% ±1.8
Switchgrass	46.6%
EH Lignin-Rich Stillage	48.2%
EH Thin Stillage Syrup	35.0%

Note: ABBK provided carbon content values for agricultural residues and wood feedstocks. The variation in carbon content is dependent on the amount of ash in the fuel sample, which is further related to the harvesting technique. For the PTE calculations, the carbon content weight percent dry basis used is the projected overall average for the site-specific feedstock.

It should be noted that agricultural residues typically contain very similar amounts of carbon. The potential-to-emit (PTE) was developed with a best case (corn stover) and worst case (maximum wood) fuel blend in mind.

Table C-5 presents the CO_2 emission rates for the proposed fuel blends compared to other common fossil fuels used for electricity generation.

Table C-5. CO_2 Emission Rates for the Proposed Fuel Blends Compared to Other Common Fossil Fuels Used for Electricity Generation

Fuels	Emission Factors (lb/MMBtu)		
	CO_2	CH_4	N_2O
Proposed Fuel Blends			
Nominal TYPICAL Fuel Blend Corn Stover: 185.3 dry ton/day EH Lignin-Rich Stillage: 320.6 dry ton/day EH Thin Stillage Syrup: 209.5 dry ton/day Biogas: 52.7 dry ton/hr	216.00	0.071	0.009
Maximum WORST CASE Fuel Blend Corn Stover: 109.3 dry ton/day EH Lignin-Rich Stillage: 384.7 dry ton/day EH Thin Stillage Syrup: 251.4 dry ton/day Biogas: 63.2 dry ton/hr	215.54	0.071	0.009
Common Fossil Fuels Used for Electricity Generation			
Natural Gas	117.00	0.002	0.0002
Distillate Fuel Oil (#1, #2 and #4)	161.30	0.007	0.001
Electric Power (Coal Combustion)	208.26	0.002	0.004

Note 4: Fossil fuel emissions factors obtained from the California Climate Action Registry, General Reporting Protocol, Version 3.1, January 2009, Tables C.7 and C.8.

The DOE[1, 2] and IPCC[3], have established that non-fossil fuel-based electricity generation (including both biomass and biogas) is assumed to yield no net

[1] Under the carbon accounting protocol of the IPCC, use of biomass fuels for energy does not add to the net amount of carbon in the atmosphere. Multiple DOE laboratories including the National Renewable Energy Laboratory (NREL) and the National Energy Technology Laboratory (NETL), recognize and follow the IPCC carbon accounting protocol.

[2] *Technical Guidelines, Voluntary Reporting of Greenhouse Gases (1605(b)) Program*, Office of Policy and International Affairs, U.S. Department of Energy, January 2007, Page 51 (available at: http://www.pi.energy.gov/documents/January2007_1605bTechnicalGuidelines(1).pdf)

emissions of CO_2 (i.e. these fuels are carbon neutral) because of the sequestration of biomass during the planting cycle. Other carbon reporting protocols, such as the California Climate Action Registry's (CCR), *General Reporting Protocol*, specifically state that CO_2 emissions from burning wood, wood waste and biogas are considered biogenic and should not be included as a direct stationary emissions in CO_2 inventories. Therefore, the proposed primary fuels are presented in this BACT as carbon neutral fuels. The natural gas used for the start-up of the boiler is a low carbon fuel as illustrated in Table C-5.

BACT based on this control option is the use of biomass as a primary feedstock that is otherwise considered to have low to no economic value or benefit (i.e. crop residuals and waste wood); and/or is a lower impacting crops (i.e. mixed warm season grasses such as switchgrass). BACT based on this control option is also limiting the boiler to using natural gas for start-up. This control option is technically feasible for the biomass-fired boiler, is an inherent part of the facility's design, and is considered a baseline control option.

2. Lower GHG-Emitting Processes/Practices/Design

   There are numerous strategies for achieving a highly energy efficient design of a new condensing-extraction steam turbine electrical power generation facility. Energy efficiency in the overall design of the power production process reduces the parasitic load, which in turn requires less fuel for process heat to generate the same amount of electricity, which directly impacts the amount of GHG emissions from the facility. All identified strategies (i.e. control options) listed in this section are technically feasible for application to the biomass-fired boiler, as well as related processes, and all are an inherent part of the facility's design.

   a. Cogeneration as a CO_2 Reduction Strategy – Cogeneration is the simultaneous production of electric power and thermal energy from a single fuel. The reduction in CO_2 emissions from employing cogeneration comes from the reduced fuel use at electric utility power plants; thus, the amount of CO_2 reduction is dependent upon the type of electric utility power generation displaced. The use of the direct-fired boiler system in which biomass feedstocks are burned directly will produce steam. This steam drives a turbine, which turns a generator that converts the power into electricity. The spent steam from the onsite power plant is then used in other process areas at the facility and to heat facility buildings, when feasible. Such combined heat and power systems greatly increase overall

[3] National
Greenhouse Gas Inventories Program, Eggleston H.S., Buendia L., Miwa K., Ngara T. and Tanabe K. (eds), *2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 4: Agriculture, Forestry and Other Land Use* (available at: http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html)

energy efficiency which has a direct impact on the amount of GHG emissions from the system.

b. Process Integration and Combustion of Co-products – ABBK will make use of the most advanced design approaches to integrate the process units and to maximize energy efficiency. Some of the major integration measures of the power generation system with other facility processes include low pressure steam supplied to the enzymatic hydrolysis process and the combustion of process co-products such as enzymatic hydrolysis residuals (including lignin-rich/lignin-lean stillage cake and thin stillage syrup), particles collected during biomass grinding, NCG vent streams, and wastewater treatment sludge and biogas. The largest co-product (on a mass basis and energy basis) is lignin-rich stillage cake, as detailed in the PTE calculations. The lignin-rich stillage cake adds approximately 210 MMBtu/hr to the total boiler system. The next largest co-product (on a mass basis and energy basis) is the thin stillage syrup, which adds approximately 109 MMBtu/hr. Wastewater treatment will consist of anaerobic treatment followed by aerobic treatment for the purpose of generating a biogas that can be added to the boiler as fuel. Anaerobic biogas would be treated to remove sulfur and then burned in the biomass boiler for an additional 42.30 MMBtu/hr of energy.

c. Heat Recovery – Periodically or continuously, some water in the boiler is removed as a means of avoiding the build-up of water impurities in the boiler. The boiler's design includes blowdown waste heat exchangers with raw water makeup. The low pressure boiler feedwater will be preheated with a combination of process waste heat and low pressure steam extraction to improve the power cycle efficiency. Also, process steam condensate is recovered from indirect process steam users and returned to the boiler feedwater system. The process condensate will be cooled with reverse osmosis water, in order to meet the temperature requirements on the condensate polishing resin. The energy is recovered in the reverse osmosis makeup water. Air preheat, which is a method of recovering heat from the hot exhaust gas of a combustion process by heat exchange with the combustion air before it enters the combustion chamber, will be included in the boiler's design. In addition to process integration techniques to be utilized, the boiler's design includes economizers to improve power cycle.

d. Boiler Operational Monitoring – Excessive amounts of combustion air used in results in energy inefficient operation because more fuel combustion is required in order to heat the excess air to combustion temperatures. Using state-of-the-art instrumentation for monitoring and controlling the excess air levels in the combustion process, will reduce the heat input by minimizing the amount of combustion air needed for safe and efficient combustion. The boiler's design includes an online stack oxygen analyzer. Oxygen levels will be monitored and the inlet air flow will be adjusted for optimal thermal efficiency within the operating limits of the boiler. Additionally, optimized air/fuel ratios, reduce not only CO_2 emissions but also NOx emissions. The boiler will be equipped with online stack oxygen analyzers as part of the continuous emission monitoring system (CEMS).

e. Boiler Maintenance – The boiler will be maintained in accordance with the manufacturer's recommendations. Maintenance of the boiler is performed to increase efficiency, ensure safety and prevent unscheduled shutdowns. Boiler outages for 10 to 14 days each year are planned for scheduled maintenance, cleaning, and "tune-up" to optimize performance.

3. Carbon Capture

Approaches to CO_2 capture can be divided into three categories:

a. Pre-Combustion

Pre-combustion capture involves reacting a fuel with oxygen or air, and/or steam to produce a "synthesis gas" or "fuel gas" composed mainly of CO and H_2. The CO is reacted with steam in a catalytic reactor, called a shift converter, to give CO_2 and more H_2. CO_2 is then separated from the gas mixture, usually by a physical or chemical absorption process, resulting in a hydrogen-rich fuel which can be used in many applications, such as a combustion turbine or boiler. This approach would require a complete redesign of the boiler so that they would burn a gaseous fuel. The November 2010 EPA GHG guidance clearly states that control technologies with inherently lower polluting processes that would fundamentally redefine the nature of the source do not need to be evaluated.[4] The DOE is proposing to provide federal funding to ABBK to support the final design, construction, and startup of a biomass-to-ethanol and biomass-to-energy production facility. The DOE funding is based on the proposed facility design. ABBK's basic or fundamental business purpose or objective for this project is dependent on the biomass-fired boiler as proposed. Therefore, pre-combustion as a control technology is technically infeasible.

b. Oxygen-Fired Combustion

In the oxygen-fired combustion (oxy-combustion) approach, the biomass is combusted in an enriched oxygen environment resulting in a flue gas that is mainly CO_2 and H_2O. This flue gas stream can directly be fed into a CO_2 compression and dehydration unit. Oxygen-fired combustion is simpler and less chemically intensive than post-combustion CO_2 capture,

[4] *PSD and Title V Permitting Guidance for Greenhouse Gases,* supra note13, Page 27.

but is less mature and similarly expensive. Because the boiler is designed to use air for combustion, the use of oxygen would require substantial redesign, and as discussed previously. Therefore, oxy-combustion as a control technology is technically infeasible.

c. Post-Combustion Capture

Post-combustion capture methods are applied to conventional combustion processes using air and carbon-containing fuels in order to isolate CO_2 from the combustion exhaust gases. Because the air used for combustion contains nearly 80% nitrogen, the CO_2 concentration in the exhaust gases is approximately 10% to 15% depending on the amount of excess air and the carbon content of the fuel. Additionally, post-combustion capture of CO_2 is a challenging application because:[5]

- The low pressure and dilute concentration dictate a high actual volume of gas to be treated;
- Trace impurities in the flue gas tend to reduce the effectiveness of the CO_2 absorbing processes; and
- Compressing captured CO_2 from atmospheric pressure to pipeline pressure (1200 to 2000 pounds per square inch (psi)) represents a large parasitic load.

Post-combustion capture methods require separating the CO_2 from other flue gases because sequestration of combustion gases is not feasible due in part to the cost of gas compression and storage. The most likely options currently identifiable for CO_2 separation and capture include: [6]

1) Absorption (chemical and physical). Chemical absorption has been the most widely used method of commercial CO_2 capture for over 60 years.[7] The main existing commercial applications include enhanced oil recovery (EOR), which involves increasing oil production rates by injecting CO_2 into oil wells. Liquid scrubbing is the most common form of chemical absorption, consisting of two contacting towers (one for CO_2 absorption and one for CO_2 desorption/absorbent regeneration). Chemical absorption is a chemical reaction that forms a loosely bonded intermediate compound. For the CO_2 capture application, a chemical solvent is exposed to the flue gas where it reacts chemically with CO_2 separating it from the other gases. The intermediate compound is then isolated and heated causing it to break down into separate streams of CO_2 and solvent. The solvent most often used is monoethanolamine (MEA). The primary concerns with

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[5] NETL, *Carbon Sequestration, CO_2 Capture* website (available at: http://www.netl.doe.gov/technologies/carbon_seq/core_rd/co2capture.html).
[6] U.S. DOE, *Carbon Capture Research* website (available at: http://www.fossil.energy.gov/programs/sequestration/capture).
[7] Herzog, H., *An Introduction to CO2 Separation and Capture Technologies,* MIT Energy Laboratory, August 1999 (available at: http://sequestration.mit.edu/pdf/introduction_to_capture.pdf).

MEA and other amine solvents are corrosion in the presence of O_2 and other impurities and high solvent degradation rates due to reactions with SO_2 and NOx. Degradation and oxidation of the solvents over time produces products that are corrosive and may require hazardous material handling procedures. These difficulties can be overcome, and this capture method is technically feasible. Other chemical absorption methods are at bench and laboratory scales of development. No CO_2 absorption technology demonstrations, except for liquid scrubbing using alkanolamines for CO_2 removal, have been successfully performed on similar type and sized sources[8].

Physical absorption processes are commonly used for CO_2 rejection from natural gas and operate at high pressure and low temperature. Use of physical absorption for CO_2 capture from combustion exhaust gas would entail a significant amount of gas compression capacity and a significant energy penalty. This capture method is presumed for the purposes of this analysis to be technically feasible, but because chemical absorption has been commercially demonstrated for CO_2 capture and physical absorption does not offer any capture/control, capital or operating cost benefits, this CO_2 capture technique will not be considered further in this analysis.

2) Adsorption (Physical and Chemical)

   Adsorption involves ducting the exhaust gas through a bed of solid material with high surface areas, such as zeolites or activated carbon to adsorb CO_2 while allowing nitrogen and other gases to pass through. Adsorption would require either a high degree of compression or multiple separation steps to produce high CO_2 concentration from exhaust gas.

3) Low-Temperature Distillation (Cryogenic Separation)

   Cryogenic separation is based on solidifying the CO_2 component of the exhaust stream by freezing it to separate it out.

4) Gas separation membranes

   Gas separation membranes (or simply membranes) capture CO_2 by separating it from the other exhaust gases using different mechanisms of separation including solution-diffusion and molecular sieving.

5) Mineralization and biomineralization (carbon calcification)

[8] The PCO_2R December 2009 report indicated that a technology demonstration project for liquid scrubbing using ammonia as the absorbent was to be conducted at the Basin Electric Power Cooperative for the 125 MW Antelope Valley Power Station. As of December 2010, Basin Electric postponed the CO_2 capture project due to technical, operational, regulatory and financial risks for installing carbon-capture technology at the conventional coal-based power plant.

Mineralization offers a leak-proof, permanent solution, whereby CO_2 is fixed into a solid matrix of minerals to form thermodynamically stable carbonate minerals. The large volumes of material involved with mineralization present significant challenges for transportation and capture, these CO_2 capture technique will not be considered further in handling.

No large-scale demonstrations of most of these technologies have been performed on similar exhaust streams. These capture methods are presumed for the purposes of this analysis to be technically feasible, but because these methods have not been commercially demonstrated for CO_2 this analysis.

Based on identified post-combustion CO_2 separation and capture methods, the only commercially demonstrated method for similar exhaust streams is chemical absorption (liquid scrubbing employing alkanolamines).

4. Carbon Transport

Once captured, CO_2 must be transported to a suitable storage site in order to achieve any environmental benefit. CO_2 pipelines are the most prevalent means of bulk CO_2 transport and are a mature market technology in operation today.[9]

Pipeline transportation of CO_2 is typically accomplished with CO_2 that is compressed to its supercritical state, involving pressures of 1200 to 2000 psi. In addition, water must be eliminated from CO_2 pipeline systems, as the presence of water results in formation of carbonic acid, which is extremely corrosive to carbon steel pipe. In overall construction, CO_2 pipelines are similar to natural gas pipelines, requiring the same attention to design, monitoring for leaks, and protection against overpressure, especially in populated areas. All of these technical issues can be addressed through modern pipeline construction and maintenance practices.

5. Carbon Storage

Deploying carbon storage in commercial-scale applications requires adequate geologic formations capable of: 1) sequestering large volumes of CO_2;
2) receiving CO_2 at an efficient and economic rate of injection; and
3) retaining CO_2 safely over extended periods.

[9] Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories, Volume 2: Energy, Chapter 5: Carbon Dioxide Transport, Injection and Geological Storage, § 5.4: *CO_2 Transport*, 2006, Page 5.8 (available at: http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_5_Ch5_CCS.pdf).

In south-central and southwest Kansas, potential geologic sequestration sites within saline aquifers and depleted oil reservoirs within the Ozark Plateau Aquifer System (OPAS) are being studied. Starting in December 2009, the University of Kansas, BEREXO Inc., Bittersweet Energy Inc., the Kansas Geological Survey, and the Kansas State University, began to evaluate potential CO_2 sequestration sites within saline aquifer and depleted oil reservoirs within the Ozark Plateau Aquifer System (OPAS). The study is focusing on the Wellington Field, with evaluation of the CO_2-EOR potential of its Mississippian Chert Reservoir and the sequestration potential in the underlying Cambro-Ordovician Arbuckle Group Saline Reservoir. [10] The purpose of the study is to provide a more detailed analysis of the storage potential of a local area within OPAS (an area covering approximately 17 counties in south-central Kansas) by modeling CO_2 injection within the Arbuckle Group Saline Aquifer and Mississippian Chert Oil Reservoir at Wellington Field (Sumner County, Kansas).

Currently, CO_2 is only captured in Kansas at a few facilities that produce high-purity CO_2.[11] In Kansas, geologic sequestration of CO_2 may be possible in all five of the geologic formations: deep saline aquifers, coal seams, oil and natural gas reservoirs, oil- and gas-rich organic shales, and basalt (the most problematic because no one knows how much CO_2 the ancient rock--deeply buried in parts of Kansas--can hold). Altogether, researchers estimate Kansas has at least 2.7 to 5.4 billion tons of potential geologic sequestration space, enough to hold almost 70 years worth of the state's stationary CO_2 production.[12] Stevens County, Kansas is located in an area known for oil and gas production, as well as deep saline formations. The proposed facility will be constructed in Section 18, Township 33S, Range 37W. Within this area are the Hugoton Gas Area, Panoma Gas Area and Gentzler oil and gas fields. Table C-6 summarizes the oil and gas production for the state and county in 2009.[13, 14]

Table C-6. Summary of Oil and Gas Production in State of Kansas and Stevens County For 2010

[10] U.S. DOE, National Energy Technology Laboratory, *Modeling CO_2 Sequestration in a Saline Reservoir and Depleted Oil Reservoir to Evaluate The Regional CO_2 Sequestration Potential of The Ozark Plateau Aquifer System, South-Central Kansas*, FE0002056, May 2010 (available at: http://www.netl.doe.gov/publications/factsheets/project/FE0002056.pdf).
[11] Kansas Geological Survey, Geologic Sequestration of Carbon Dioxide in Kansas, Public Information Circular 27, December 2008 (available at: http://www.kgs.ku.edu/Publications/PIC/pic27.html).
[12] *Geologic Sequestration of Carbon Dioxide in Kansas*, supra note 27.
[13] Kansas Geological Survey, *State Production and Historical Information* website (available at: http://www.kgs.ku.edu/PRS/petro/state.html).
[14] Kansas Geological Survey, *Stevens County – Oil and Gas Production* website (available at: http://www.kgs.ku.edu/PRS/County/rs/stevens.html).

Oil Production	Production (bbls)	No. of Wells	Cumulative (bbls)
State-Wide	40,467,966	45,999	6,353,888,940
Stevens County	678,852	139	26,956,160
County Percentage	1.67%	0.30%	0.42%
Gas Production	**Production (mcf)**	**No. of Wells**	**Cumulative (mcf)**
State-Wide	331,539,924	25,232	39,055,863,258
Stevens County	48,758,979	2,195	8,747,453,719
County Percentage	15.0%	8.70%	22.40%

Note: Units are barrels (bbls) and 1000 cubic feet (mcf).

In Kansas, concerns have been raised about regulating CO_2-EOR and other geologic sequestration activities and whether the CO_2 would be trapped in these reservoirs or move back to the surface over time. Because Kansas has long been drilled for oil and gas and some areas have been very densely drilled, concerns also exist that CO_2 could move back to the surface through poorly plugged or long-forgotten wells.

According to the Kansas Geological Survey, sequestration in Kansas needs to be studied in more detail to determine if oil and natural gas reservoirs and coal beds have the capacity to take and hold CO_2. In addition, a variety of legal issues, such as ownership of the underground pore space used for sequestration, would need to be resolved, and a workforce would have to be developed. Ultimately, regulatory decisions, economics, and a well-defined environment for GHG management will highly influence any decisions concerning the feasibility of geologic sequestration.[15]

In addition to the CO_2 storage options already discussed, the other primary storage option available includes using terrestrial applications. Terrestrial sequestration is the enhancement of CO_2 uptake by plants that grow on land and in freshwater and, importantly, the enhancement of carbon storage in soils where it may remain more permanently stored.

In general, croplands store less carbon than grasslands which store less carbon than forests. Grasslands are particularly good at storing carbon in soils because they often have extensive and deep roots. DOE determined in the EIS that "warm season grass production would likely occur on marginal and non-harvested cropland, pasture, and former CRP lands. Bioenergy crops have the potential to reduce atmospheric carbon by building up soil carbon levels, especially when planted on lands where soil carbon levels have been reduced by intensive tillage, such as marginal cropland. In instances where pasture or former CRP lands would be converted to warm season grass production, exchanging one system of perennial vegetation for another would be expected to involve minimal environmental changes, including greenhouse gas

[15] *Geologic Sequestration of Carbon Dioxide in Kansas*, supra note 27.

emissions. A 2007 study on the Life-Cycle Energy and Greenhouse Gas Emission Impacts of Different Corn Ethanol Plant Types[16] concluded that cellulosic ethanol produced from switchgrass [switchgrass is a type of warm season grass] clearly offers the greatest energy and [greenhouse gas] benefits (by far)."[17] Based on these considerations, DOE concluded that in the event warm season grasses were to replace corn stover as the dominant feedstock, the net result to greenhouse emissions would be beneficial. By the year 2018, ABBK anticipates approximately 240,000 acres (970 square kilometers) of mixed warm season grasses will supply approximately 1,900 dry tons (1,700 metric tons) per day, which equates to 75% of the feedstock demand. The change from corn stover to grasses is dependent first on the construction of the facility to generate the crop demand, and second on the negotiation of contracts with local farmers to change their farming practices from corn to grasses. ABBK's long-term operational plan for this facility is based on the feedstock change to mixed warm season grasses.

Terrestrial sequestration provides an opportunity for low-cost CO_2 emissions offsets. Storing carbon in terrestrial ecosystems can be achieved through maintenance of standing aboveground biomass, utilization of aboveground biomass in long-lived products, or protection of carbon (organic and inorganic) compounds present in soils.[18] Because the proposed source consists of biomass-fired boiler, this type of CO_2 storage is essentially being implemented as part of the facility's design; therefore, terrestrial sequestration is considered a baseline control option.

6. Carbon Beneficial Uses

In addition to using CO_2 for enhanced oil recovery (EOR), there are many other possible beneficial and revenue-generating uses for captured CO_2 in various stages of development. Technologies are being developed today that synthesize solid materials such as plastics, or carbonates that can be used in cement or glass, from a CO_2 feedstock. There are other technologies under development that do not provide long-term storage of CO_2, but which still could reduce overall GHG emissions by either 1) using CO_2 in a way that displaces the emission of other GHGs, or 2) converting CO_2 into a chemical that can in turn displace the emission of other GHGs. An example of the former is using CO_2 as a refrigerant that substitutes for chemicals currently used in refrigeration that are far more potent greenhouse gases than CO_2, such as hydrofluorocarbons (HFCs). An example of the latter is the wide array of "CO_2-to-fuel" technologies being researched with the goal of producing liquid

[16] Michael Wang, et. al., Center for Transportation Research, Argonne National Laboratory *Life-Cycle Energy and Greenhouse Gas Emission Impacts of Different Corn Ethanol Plant Types*, first published May 22, 2007 (available at: http://iopscience.iop.org/1748-9326/2/2/024001/pdf/1748-9326_2_2_024001.pdf).
[17] *Final Environmental Impact Statement for the Proposed Abengoa Biorefinery Project near Hugoton, Stevens County, Kansas*, supra note 11, Page 4-30.
[18] Gary K. Jacobs, et. al., Oak Ridge National Laboratory, Oak Ridge, TN, *Carbon Sequestration in Terrestrial Ecosystems: A Status Report on R&D Progress*, August 2000 (available at: http://www.netl.doe.gov/publications/proceedings/01/carbon_seq/3C1.pdf).

fuels ranging from methanol or ethanol to gasoline or diesel out of CO_2 and water, along with an energy input (preferably from a CO_2-free source such as solar or wind). Fuels produced from waste CO_2 could displace the use of petroleum-derived fuels, which would result in reduced net GHG emissions.

Some of the better-known types of CO_2-to-fuel technologies are biologically based and use algae and other photosynthetic microorganisms in the conversion of CO_2, water, and sunlight into liquid fuel. A number of different companies are trying to commercialize technologies that use photosynthetic microbes to convert CO_2 to fuel. Some other uses of CO_2 that are being researched do not clearly reduce GHG emissions directly or indirectly, but still provide some other public benefit such as displacing the use of the toxic chemicals or saving water. Examples include using CO_2 as a solvent in place of perchlorethlyene for dry cleaning, or using CO_2 as a non-toxic grain silo fumigant.

The many different technologies being investigated for the beneficial use of CO_2 vary widely in their stages of development, from those being tested at the bench-scale, to technologies that are close to commercialization. They also vary widely in their potential to impact overall GHG emissions. There is a need to better understand the viability of the various technological options for CO_2 use and their potential to incentivize industrial carbon capture and provide substantive GHG emissions reductions.

The majority of CO_2 in the merchant market[19] is used for EOR (approximately 70-80%),[20] along with a significant portion used in the food processing industry. CO_2 currently being utilized that has been separated from flue gas or chemical process streams is generally either captured from relatively pure flue gas streams or from process streams where CO_2 capture and separation is necessitated by a need for product purity (e.g., natural gas pipelines or ammonia production).[21]

For the purposes of this BACT analysis, the feasibility of CO_2 capture, including economic, energy and environmental impacts, must first be established before storage and beneficial use options can be fully explored.

D. Rank Technically Feasible Options

Table C-7 presents the ranked technically feasible control options.

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[19] Market in which CO_2 is bought and sold competitively by multiple market participants.

[20] Tiina Koljonen, Hanne Siikavirta, Ron Zevenhoven, *CO_2 Capture, Storage and Utilization in Finland*, Project Report, VTT Processes, Systems and Models, August 29, 2002 (available at: www.vtt.fi/inf/julkaisut/muut/2002/co2capt.pdf).

[21] Reed, John, California Carbon Capture and Storage Review Panel, *Technical Advisory Committee Report – Beneficial Use of Carbon Dioxide*, October 4, 2010, Page 1 (available at: http://www.climatechange.ca.gov/carbon_capture_review_panel/meetings/2010-10-21/white_papers/Beneficial_Use_of_Carbon_Dioxide.pdf)

Table C-7. Ranked Control Options

Control Technology	Emission Rate (tons CO_2/year, excludes CH_4 and N_2O)	Reduction Efficiency	Emissions Reduction (tons CO_2/year, excludes CH_4 and N_2O)
Carbon Capture and Storage (CCS)	~ 48,000	90%	~ 433,500
Carbon Capture for Beneficial Uses	~ 48,000	90%	~ 433,500
Baseline (Fuel Type Restriction, Use of Lower GHG-emitting Processes/Practices/Design and Terrestrial Sequestration	481,652	N/A	N/A

The use of low-carbon and carbon neutral fuels, use of an aggressive lower GHG-emitting processes and practices through an energy-efficient design to reduce CO_2 emissions, and terrestrial sequestration control options are an inherent part of the facility's design and considered baseline control options. No emissions reduction credit is taken for the implementation of the baseline control options. The baseline presented above represents the design with the highest efficiency improvements limited to the maximum worst-case fuel blend discussed in Section 2.4.2.2. of the GHG BACT analysis prepared by ABBK. A detailed analysis of the baseline CO_2 control option(excluding terrestrial sequestration benefits)and three different operational cases (Case 1, Case 2 and Case 3) are shown in Table C-8.

Table C-8. Detailed Comparison of the Impacts of Certain Heat Recovery Strategies on the Cogeneration System

Heat Recovery Strategies on the Cogeneration System	Heat Recovery Strategy Implemented (Yes/No)			
	Baseline Case (Proposed System)	Case 1	Case 2	Case 3
Biomass Boiler (Fuel Type Restriction)	Yes	Yes	Yes	Yes
Air Preheat	Yes	Yes	Yes	No
Economizer	Yes	Yes	Yes	No
High Pressure Boiler Feedwater Preheater	Yes	Yes	No	No
Low Pressure Boiler Feedwater Preheaters	Yes	Yes	No	No
Process Waste Heat Integration	Yes	No	No	No
Impacts from Implementing Each Heat Recovery Strategy				

Gross Power Production, MWe	21.8	19.3	20.8	20.8
Estimated Net Power to Grid, MWe	2.8	0.3	1.8	1.8
Heat Rate, Btu/kW-hr	21,431.2	24,207.3	23,802.9	27,543.3
Cycle Efficiency, %	15.92%	14.10%	14.33%	12.39%
Overall Efficiency, %	183.6	183.6	183.6	183.6
Boiler Steam Production, lb steam/hr	325,000	325,000	325,000	325,000
CO_2e Production (Maximum WORST CASE Fuel Blend), lb CO_2e/hr	109,966	109,966	116,645	135,165
CO_2e/Steam Ratio (Maximum WORST CASE Fuel Blend), lb CO_2e/lb steam produced	0.34	0.34	0.36	0.42

The technically feasible control options for further controlling CO_2 emissions or reducing overall CO_2 impacts from the biomass-fired stoker boiler is carbon capture with either long term storage through geologic sequestration or beneficial use of the CO_2 as a consumer product. For the purposes of this BACT analysis, chemical absorption is assumed to represent the best post-combustion CO_2 capture option that has been commercially demonstrated. The evaluation of the control options in this BACT analysis focuses first on the effectiveness of CO_2 capture, including economic, energy and environmental impacts; and then if CO_2 capture is determined to be cost-effective, storage and beneficial use options will be evaluated.

E. Evaluate Technically Feasible Control Options

CCS in biomass-fired power plants may result in net CO_2 removal from the atmosphere. However, biomass plants are typically small (25 to 50 MWe verses 500 to1000 MWe coal power plants). Thus the CCS cost per kW is roughly twice as high as the cost in coal plants.[22] For the purposes of this BACT analysis, the feasibility of CO_2 capture, including economic, energy and environmental impacts will be evaluated first. If CO_2 capture is determined to be cost-effective, storage and beneficial use options will be evaluated. As established above, the only commercially demonstrated post-combustion CO_2 separation and capture method for similar exhaust streams is chemical absorption. The general method involves exposing a gas stream to an aqueous amine solution which reacts with the CO_2 in the gas by an acid-base neutralization reaction to form a soluble carbonate salt:

$$2RNH_2 + CO_2 + H_2O = (RHN_3)_2CO_3$$

[22] International Energy Agency (IEA), *IEA Energy Technology Essentials, CO_2 Capture and Storage*, ETE01, December 2006, Page 3 (available at: http://www.iea.org/techno/essentials1.pdf).

This reaction is reversible, allowing the CO_2 gas to be liberated by heating in a separate stripping column. Therefore, the major advantage to this technique is that, in the ideal situation, the amine is not consumed and may be continuously recycled through the process. The amine used in this process is most commonly one of several alkanolamines including monoethanolamine (MEA). The technology was originally developed not for the purpose of carbon sequestration, but in order to "sweeten" natural gas streams by removing CO_2. More recently, it was successfully adapted for recovery of CO_2 from flue gas of coal-fired electric power generating plants. Currently, there are three (3) electric power generating stations in the U.S. that capture CO_2 from flue gas and six (6) other major flue gas CO_2 capture facilities worldwide. All nine (9) use MEA as the chemical sorbent.[23]

The disadvantage of the chemical absorption process is that it would consume a significant amount of the energy produced. A typical "energy penalty", which is defined as the percentage of the net power output consumed for the chemical absorption process installed on a conventional coal-fired power plant is between 25%-37%.[24] This does not include transportation and injection costs, which would increase the economic burden even further. It is expected that the energy penalty for the biomass-fired boiler would be equivalent to that of a coal-fired power plant due to the similar CO_2 emission rates.

Certain factors affect the chemical absorption process implementation costs. These factors include the following:

1. The primary concerns with MEA and other amine solvents are corrosion in the presence of O_2 and other impurities and high solvent degradation rates due to reactions with SO_2 and NOx. Post-combustion control of SO_2 and NOx before the chemical absorption system can reduce the affects of these pollutants.

2. The flue gas should be cooled to around 40 °C for the CO_2 absorption to take place. This requires additional cooling water.

3. Steam heat is required to heat the solvent to release the CO_2 during regeneration.

4. Parasitic power is required for pumping the fluids through the chemical absorption system.

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[23] National Energy Technology Laboratory, *Degradation of Monoethanolamine Used in Carbon Dioxide Capture from Flue Gas of a Coal-fired Electric Power Generating Station* (available at: http://www.netl.doe.gov/publications/proceedings/01/carbon_seq/4b3.pdf)
[24] *Technical Overview of Carbon Dioxide Capture Technologies for Coal-Fired Power Plants,* supra note 18, Page 5.

5. Heat exchangers, scrubber towers, absorption towers, and heaters are required for the process.

6. Replacement cost of the chemical solvent is high because regeneration is only for few cycles.

7. Degradation and oxidation of the solvents over time produces products that are corrosive and may require hazardous material handling procedures.

8. Work to date has used chemical absorption on a small scale. Issues involved with scaling up the existing technology will need to be addressed.

9. Reliable operation of packed towers used in chemical absorption systems will need to be demonstrated.

F. Economic and Energy Impacts

Another shortcoming of the chemical absorption process is that it has a relatively high capital cost. The large size of the major components significantly influences the capital cost. The footprint of the biomass-fired boiler footprint is expected to increase approximately 60% with the addition of chemical absorption-based CO_2 capture.

Because post-combustion CO_2 capture has not been commercially demonstrated on biomass-fired electricity generating systems, there are no specific reference documents or demonstration projects that can be relied upon. Site-specific cost estimates for the purpose of constructing a commercial scale CO_2 capture system would require significant time and engineering investment, as well as an initial bench-scale/pilot test prior to full scale application. Therefore, for the purposes of this BACT analysis, the Plains CO_2 Reduction (PCOR) Partnership, the PCOR report, *Regional Emissions and Capture Opportunities Assessment – Plains CO_2 Reduction (PCOR) Partnership (Phase II)* was relied upon for comparison purposes of the estimates CO_2 capture costs presented herein. A copy of the PCOR report has been included in the application.

Although the state of Kansas is not specifically included in the PCOR report, ABBK is a member of the PCOR Partnership and the cost analyses presented in the report were assumed comparable as the PCOR report included the neighboring states: Missouri and Nebraska. Capture and compression costs and power requirements for ethanol plants, gas-processing plants, and electricity-generating facilities were estimated in the PCOR report using the Integrated Environmental Control Model (IECM), Version 5.22 (released January 28, 2008) (IECM, 2008). The IECM is a desktop computer model that was developed at Carnegie Mellon University with funding from NETL, which is design to support a variety of technology assessment and strategic planning activities for the fossil fuel-fired power plants: pulverized coal plant, natural gas combined-cycle (NGCC) plant, coal-based integrated gasification combined-cycle (IGCC) plant, and oxyfuel combustion plant.

The results from the IECM simulations conducted for the PCOR report show a significant cost and energy penalty for capturing 90% of the CO_2 emitted from electricity-generating facilities. The PCOR report used a minimum 100 MW limit primarily because the economics and power requirements of capturing CO_2 at units smaller than 100 MW would make electric generation at these units no longer feasible. In addition, the IECM has a lower estimation boundary level of 100 MW, meaning that values calculated using the IECM for units smaller than 100 MW may not depict the true costs and power requirements.

For the purposes of the GHG BACT analysis, the data contained in the PCOR report was relied upon to fully demonstrate to KDHE that the cost of add-on CO2 control at the proposed biomass-to-energy system is not economically feasible. The PCOR report estimated the costs associated with capture, drying, compression separately from the cost of CO_2 transportation by pipeline for sequestration or EOR. Injection costs for sequestration or any monetary value assigned to the CO_2 for EOR have not been included in the cost or energy estimates.[25] Including the cost of replacement power, the per-ton cost associated with CO_2 capture, drying, and compression of 90% of the CO_2 produced at the PCOR region's power plants would be $71 per short ton CO_2 avoided.[26] The increase in the cost of producing electricity caused by the capture, compression, and transport of the CO_2 was estimated in the PCOR report to be 159% to 189% with CO_2 capture, drying, and compression of 90% of the CO_2 produced.[27]

The nearest commercial CO_2 pipeline terminus is at Guymon Oklahoma, approximately 40 miles south of the proposed facility at the Mobil Exploration and Producing U.S. Postle Field Unit. ABBK estimated that the capital investment to install a CO_2 pipeline to connect to the Mobil Exploration and Producing U.S. Postle Field Unit would be $35 per linear foot, or $7,392,000, excluding right-of-way acquisitions, dehydration equipment, compressors, surge storage tanks, booster pumps, and operation and maintenance. The preparation of the CO_2 for transport via pipeline will result in additional energy penalties, as well as additional emissions (including CO_2). Because evaluations of the OPAS are ongoing,[28] it has not been fully demonstrated that geologic sequestration in Kansas is technically feasible, therefore, transportation via pipeline for EOR is currently the only commercially demonstrated control option available.

The CO_2 value of $45 per metric ton ($41 per short ton) delivered at pressure to the field is presented as the base case in the NETL report, *Storing CO_2 with*

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[25] *Regional Emissions and Capture Opportunities Assessment – Plains CO_2 Reduction (PCOR) Partnership Phase II*, supra note 26, Pages vi through viii.
[26] *Regional Emissions and Capture Opportunities Assessment – Plains CO_2 Reduction (PCOR) Partnership Phase II*, supra note 26, Table 12.
[27] *Regional Emissions and Capture Opportunities Assessment – Plains CO_2 Reduction (PCOR) Partnership Phase II*, supra note 26, Table 13.
[28] Kansas Geologic Survey, *South-central Kansas CO_2 Project* website (available at: http://www.kgs.ku.edu/PRS/Ozark/index.html).

Enhanced Oil Recovery.[29] Other estimates indicate that the CO_2 costs with EOR as low as \$10 per short ton. Based on the costs presented in the PCOR report, the per-ton cost associated with CO_2 capture, drying, and compression of 90% of the CO_2 produced would be \$71 per short ton CO_2 avoided. It is assumed that because the proposed biomass-to-energy system will be sized will be nominally rated at 22 MW and because the flue gases from biomass combustion will be similar to coal combustion (similar CO_2 concentration, pollutants and control technologies (SO_2 scrubber and SNCR), the PCOR costs are similar to the expected costs for CO_2 capture, drying and compression at the proposed facility.

Comparing the CO_2 value of \$41 per short ton for EOR to the CO_2 capture cost of \$71 per short ton, the implementation of CO_2 capture at the ABBK facility is not cost effective. Further, CO_2 capture would result significant and adverse energy and environmental impacts due to the parasitic consumption of steam and electricity, additional emissions generated during CO_2 dehydration and compression and raw material usage.

G. Environmental Impacts

The EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases*, states that, "EPA believes that it is appropriate for permitting authorities to account for both existing federal and state policies and their underlying objectives in evaluating the environmental, energy and economic benefits of biomass fuel. Based on these considerations, permitting authorities might determine that, with respect to the biomass component of a facility's fuel stream, certain types of biomass by themselves are BACT for GHGs.

Under the Energy Policy Act of 2005 (EPAct 2005), Congress directed the DOE to carry out a program to demonstrate the commercial application of integrated biorefineries for the production of biofuels, in particular ethanol, from lignocellulosic feedstocks. Accordingly, in February 2006, DOE issued a funding opportunity announcement for the design and construction of commercial-scale integrated biorefineries intended to demonstrate the use of a wide variety of lignocellulosic feedstocks to produce combinations of liquid transportation fuels (biofuels), bio-based chemicals, substitutes for petroleum-based feedstocks and products, and energy in the form of electricity or useful heat (biopower). In that announcement, DOE also encouraged the use of a wide variety of lignocellulosic feedstocks, but not those biomass components specifically grown for food, and encouraged the use of various technologies to collect and treat the wide variety of biomass feedstocks.

On February 28, 2007, DOE, announced the selection of six biorefinery projects for negotiation of financial assistance awards, one of which was the ABBK biomass-to-ethanol and biomass-to-energy production facility. ABBK proposed an innovative approach to biorefinery operations that would involve production of

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[29] NETL, *Storing CO_2 with Enhanced Oil Recovery*, DOE/NETL-402/1312/02-07-08, February 7, 2008 (available at: http://www.netl.doe.gov/energy-analyses/pubs/Storing%20CO2%20w%20EOR_FINAL.pdf)

a biofuel and energy in the form of steam that can be used to meet energy needs and displace fossil fuels, such as coal and natural gas. ABBK proposed to locate the facility in Kansas to qualify for state tax credits for the construction of cellulosic ethanol facilities (Kansas Energy Development Act of 2006; Kansas Senate Bill 303), which would make the biorefinery a more viable commercial operation.

H. Establish BACT

ABBK proposes that GHG BACT for the biomass-fired stoker boiler consist of the following:

1. Restriction of the fuel type to biomass that is otherwise considered to have low to no economic value or benefit (i.e. crop residuals and waste wood); and/or is a lower impacting crops (i.e. mixed warm season grasses such as switchgrass);

2. Energy efficient design, incorporating cogeneration, process integration, combustion of co-products, heat recovery and operational and maintenance monitoring.

These control options are technically feasible for the biomass-fired stoker boiler and are an inherent part of the facility's design. ABBK proposes that the BACT limit for the biomass-fired boiler be 0.34 lb CO_2e /lb of steam produced. This limit is based on the following:

Steam production rate = 325,000 lb of steam/hr
CO_2e emission rate based on the fuel specifications = 109,965 lb CO_2e/hr

$$CO_2e \text{ BACT Limit} = \frac{109{,}965 \text{ lb } CO_2e / \text{hr}}{325{,}000 \text{ lb of steam} / \text{hr}}$$

$$CO_2e \text{ BACT Limit} = 0.34 \text{ lb } CO_2e / \text{lb steam produced}$$

ABBK proposes the use of the top performing control technology to control GHG emissions from the biomass-fired boiler. ABBK will to record the fuel type and quantity combusted in the boiler. Feedstock properties, unburned carbon in ash and sorbent reactivity will be tested weekly. Fuel blends will be reviewed for compliance with the established emission limits prior to combustion and gas parameters: percent oxygen, flow rate, temperature, and pressure.

The BACT limit proposed is based on a "lb CO_2e/lb steam produced" limit instead of the engineering estimate which used "lb CO_2e/MMBtu" because the steam pressure produced will be continuously monitored. An hourly steam production rate output monitoring device for the stoker boiler will be calibrated and maintained according to manufacturer's specifications. ABBK proposes that that simplest compliance method be based on steam produced, not the boiler heat input rate. ABBK will maintain a rolling 12-month calculation of the CO_2e emissions of N2O and CH4 based upon the most recent performance test. This calculation will be combined with the emissions data acquired by the CO_2 CEMS. The emission limit is based on a maximum potential to emit, expressed in pounds of CO_2e per pound of steam produced, averaged over 30 day rolling periods.

III. Fermentation and Distillation GHG BACT Analysis

A. Source Description

The CO_2 generated from the biomass co-fermentation process (Area 16000) and beer well (T-18101) will be routed through the enzymatic hydrolysis fermentation CO_2 scrubber (S-18185). The rated control efficiency will be equal to or greater than 99 percent. The CO_2 generated from the biomass ethanol recovery process (Area 18000) will be routed through the enzymatic hydrolysis distillation vent scrubber (S-18180). The distillation vent scrubber vent feeds into the enzymatic hydrolysis fermentation CO_2 scrubber (S-18185) for further control efficiency.

The vent streams routed to the scrubbers are expected to be saturated with water since the process tanks contain primarily CO_2, other gases (O_2/N_2) and water. These vent streams also are expected to contain trace amounts of contaminants such as ethyl alcohol (ethanol), fusel oils, H_2S, NOx, etc. Table C-9 presents a comparison of the enzymatic hydrolysis CO_2 scrubber (S-18185) vent stream to a traditional starch fermentation scrubber vent stream.

Table C-9. Fermentation / CO_2 Scrubber Comparison

Constituents in Scrubber Vent Streams	Typical Starch Fermentation Scrubber (84 MMGPY)		ABBK Scrubber (S-18185) (30 MMGPY)	
	lb/hr	wt.%	lb/hr	wt.%
Total	49,199	100.0%	23,424.48	100%
Water	747	1.5%	255.48	1.1%
Alcohol	2	0.0%	1.28	0.005%
Byproducts	5	0.0%	0.65	0.003%
CO_2	46,993	95.5%	20,387	~88%
Air	1,453	3.0%	2,548	~11%

Note: The typical starch fermentation scrubber information was obtained from ABBK's scrubber vendor, Vogelbusch.

The enzymatic hydrolysis CO_2 scrubber (S-18185) CO_2 concentration is significantly lower than a typical starch plant, due to the addition of air during fermentation. Additional air is needed for the particular organism used in the enzymatic hydrolysis fermentation process. The typical starch fermentation scrubber information was obtained from the facility's scrubber vendor, Vogelbusch. Vogelbusch engineering data indicates that a typical starch fermentation scrubber will have a CO_2 concentration of 95.5% by weight. Abengoa Bioenergy of Nebraska, LLC has documented it's starch fermentation scrubber's typical CO_2 concentration is greater than 98% by weight.

The scrubbers will be packed-tower wet scrubbers, which allow for ethanol vapors to be collected in order to produce a higher product yield, and consequently the units control emissions of VOCs, HAPs, organic acids, furfural and higher alcohols. The scrubber systems will recover more than 99% of the ethanol from the vapor stream and return the ethanol to the process downstream. The water from the wet scrubbers is pumped back into the process for recycling. The distillation vent scrubber vent feeds into the enzymatic hydrolysis fermentation CO_2 scrubber (S-18185) for further control efficiency.

B. Identify Available Control Options

The following control options were identified and considered in determining BACT:

1. Monitoring enzymatic hydrolysis process efficiency;

2. Carbon capture and storage ("CCS", also referred to as "carbon capture and sequestration");

3. Carbon capture for beneficial uses;

4. Develop and implement an LDAR program, in accordance with NSPS, Subpart VVa (40 CFR §60.480a through §60.489a), as proposed for the other fugitive HAR pollutants: VOC and HAP; and

5. Combination of these control options.

   There are two (2) broad strategies for reducing GHG emissions from the two enzymatic hydrolysis scrubbers at the proposed facility. The first is to minimize the production of GHG through monitoring enzymatic hydrolysis process efficiency. The EH process efficiency is an integral part of the facility's design and is considered the baseline for this BACT analysis.

   The second strategy for reducing GHG emissions is carbon capture and storage ("CCS", also referred to as "carbon capture and sequestration") or carbon capture for beneficial uses. Because of the low CO2 concentration in the scrubber vent streams (88%), the CCS and carbon capture for beneficial uses discussion presented in the biomass-fired boiler section #2 is applicable.

Although the CO_2 concentration is 88%, this stream is still not considered a "high purity CO_2 Stream" like other traditional starch plant fermentation vent streams, where the CO_2 concentration is greater than 95% and usually 98% to 99% before CO_2 capture is performed for commercial applications.

Implementation of an LDAR program is not intended to control emissions beyond the baseline. The LDAR program is used to monitor equipment leaks for repair. For the fermentation and distillation operations, CO2 emissions from equipment leaks were estimated to be less than 1 lb/hr.

C. Eliminate Technically Infeasible Control Options

Two main options identified for control of CO_2 emissions from the two enzymatic hydrolysis scrubbers: 1) monitoring enzymatic hydrolysis process efficiency; and 2) CCS and/or carbon capture for beneficial uses. Table C-10 summarizes the technical feasibility/infeasibility determination discussed in this section.

Table C-10. Technical Feasibility/Infeasibility Determination Summary

Potentially Available Control Option	Determination Result	Determination Reason
Monitoring Enzymatic Hydrolysis Process Efficiency	Technically Feasible	Inherent part of the facility's design, and considered a baseline control option.
Carbon Capture Using Post-Equipment Capture	Technically Feasible	Chemical absorption has been the most widely used method of commercial CO2 capture and is the primary CO2 capture technology further analyzed.
Carbon Transportation	Technically Feasible	Technical issues can be addressed through modern pipeline construction / maintenance practices.
Carbon Storage through Geologic Sequestration	Technically Feasible	In Kansas, geologic sequestration of CO2 may be possible in all five of the geologic formations: deep saline aquifers, coal seams, oil ad natural gas reservoirs, oil- and gas-rich organic shales, and basalt
Carbon Storage through Terrestrial Sequestration	Technically Feasible	Inherent part of the facility's design; considered a baseline control option.
Carbon Beneficial Uses	Technically Feasible	The many different technologies being investigated for the beneficial use of CO2 vary widely in their stages of development; from those in bench-scale, to those close to commercialization.
Combination of these Control Options	Technically Feasible	See reasons above.

The technical feasibility of the control options are discussed below.

1. Monitoring Enzymatic Hydrolysis Process Efficiency

There are numerous strategies for achieving a highly efficient enzymatic hydrolysis process. All identified strategies (i.e. control options) listed in this section are technically feasible for application to the scrubbers, and all are an inherent part of the facility's design.

a. Monitoring the Enzymatic Hydrolysis Process Efficiency Related to CO_2 Production in Fermentation – This strategy is the primary GHG BACT control technology option. CO_2 production in fermentation is a function of the yeast, and selected micro-organism. A healthy and optimized organism will produce more ethanol and less CO_2.

b. Energy Efficient Heat Integration – The enzymatic hydrolysis process is integrated with the cogeneration facility to maximize energy efficiency. This integration is discussed in Section 2.4 of the GHG BACT analysis prepared by ABBK. Energy efficient heat integration is more important to the boiler GHG than the CO_2 scrubber (EP-18185) and distillation vent scrubber (EP-18180) GHG.

c. Water Recycling – Process-related water will be recycled whenever possible to reduce the facility's consumption.

d. Co-product Production – Valuable co-products will be generated during the enzymatic hydrolysis process. The valuable co-products include products such as enzymatic hydrolysis residuals (including lignin-rich/lignin-lean stillage cake and thin stillage syrup) and wastewater treatment biogas. These products can either be sold as a consumable product or combusted as a supplemental fuel in the biomass-fired boiler.

2. Carbon Capture

Section II of Appendix D (or Section 2.4 of GHG BACT analysis prepared by ABBK) details the carbon capture control option technical feasibility determination. The information presented in the biomass-fired boiler section is not repeated herein. For the fermentation and distillation scrubbers, the pre-combustion and oxy-combustion approaches are not applicable. Carbon capture using post-equipment capture is equivalent to post-combustion capture. The only commercially demonstrated method for similar exhaust streams (low CO_2 concentrations) is chemical absorption.

3. Carbon Transport and Storage

Section II of Appendix D (or Section 2.4 of GHG BACT analysis prepared by ABBK) details the carbon transport and storage technical feasibility determination. The information presented in Section II above is not repeated herein.

Terrestrial sequestration applies to the fermentation and distillation scrubbers because the emissions associated with these scrubbers are biogenic CO_2 emissions. Because the proposed source will utilize biomass in the production of ethanol, this type of CO_2 storage is essentially being implemented as part of the facility's design; therefore, terrestrial sequestration is considered a baseline control option.

3. Carbon Beneficial Uses

Section II of Appendix D (or Section 2.4 of GHG BACT analysis prepared by ABBK) details the carbon beneficial uses control option technical feasibility determination. The information presented in Section II above is not repeated herein.

D. Rank Technically Feasible Options

Table C-11 presents the ranked technically feasible control options. The use of monitoring enzymatic hydrolysis process efficiency to reduce CO_2 emissions, and terrestrial sequestration control options are an inherent part of the facility's design and considered baseline control options. No emissions reduction credit is taken for the implementation of the baseline control options. The baseline presented in Table C-11 represents the design with the highest efficiency improvements.

Table C-11. Ranked Control Options

Control Technology	Expected Emission Rate (tons CO_2/year)	Reduction Efficiency	Expected Emissions Reduction (tons CO_2/year)
Carbon Capture and Storage (CCS)	~ 8,800	90%	80,000
Carbon Capture for Beneficial Uses	~ 8,800	90%	80,000
Baseline (Monitoring Enzymatic Hydrolysis Process Efficiency and Terrestrial Sequestration)	88,360	N/A	N/A

E. Evaluate Technically Feasible Control Options

The implementation of CCS and carbon capture for beneficial uses on the fermentation and distillation scrubbers is similar to the implementation of these control options on the biomass-fired boiler. The CO_2 concentrations in the scrubber's vent streams are similar to the CO_2 concentrations expected in the biomass-fired boiler's flue gases. The low purity (88% CO_2 concentration) in the fermentation and distillation vents makes these vent streams undesirable for CO_2 processing companies.

Because the largest CO_2 emission sources at the facility are the biomass-fired boiler, the implementation of a CCS control option (excluding terrestrial sequestration) is based on the cost-effectiveness of such a system applied to the boiler. As discussed in detail in the biomass-fired boiler section, using CCS or carbon beneficial uses to reduce CO_2 emissions from the boiler is technically feasible but would entail significant, adverse economic, environmental and energy impacts due to increased fuel usage in order to meet the steam and electric load requirements of the CCS systems. Therefore, the use of CCS and carbon beneficial uses technologies were determined not to be cost effective for control of CO_2 from the boiler and subsequently, are not cost effective for the fermentation and distillation CO_2 emissions, which are less than 88,360 tons/yr CO_2e.

F. Establish BACT

ABBK proposes that GHG BACT for the fermentation scrubber vent stream consist of an efficient design, incorporating energy efficient heat integration, water recycling, and co-product production that make the overall process efficient and economical.

These control options are technically feasible for the enzymatic hydrolysis process and are an inherent part of the facility's design. ABBK proposes that the BACT limit be 5.89 lb CO_2e/gal anhydrous ethanol produced for the enzymatic hydrolysis fermentation CO2 scrubber stack (EP-18185), averaged over a 30-day rolling period. These proposed emission limits are based on the average continuous flow CO_2 concentrations.

CO_2e emissions will be determined based on the required stack testing to be completed upon startup. Continuous stack monitoring equipment will be installed to monitor operational indicators and CO_2. Emissions will be averaged over a 30-day rolling period for compliance.

IV. <u>Flare GHG BACT Analysis</u>

A. Source Description

The facility design will incorporate a flare (EP-09001) for control of process vents flow, biogas and product loadout vapors. The vent streams will normally be vented to the biomass-fired boiler for combustion; however these streams may be vented to the flare as needed for up to 3,960 hours per year.

The flare will have the PTE of biogenic and anthropogenic GHG emissions (CO_2, CH_4, and N_2O) because it is used to combust process vent streams, biogas, and product loadout vapors. Combustion of the process vent streams, biogas, ethanol, natural gas and gasoline in the flare results in the emissions of NOx, SO_2, CO, VOC, PM/PM_{10}/$PM_{2.5}$ and biogenic and anthropogenic GHG emissions (CO_2, CH_4, and N_2O). Flaring destroys 2,119 lb/hr CH_4 (44,503 lb/hr CO_2e), and generates 10,170 lb/hr CO_2, for a total net reduction of CO_2e equal to 34,333 lb/hr. Total CO_2e emissions from this source (including emissions from natural gas combustion in the flare's pilot) are 10,185 lb/hr.

B. Identify Available Control Options

The flare is incorporated in the process design as a type of control technology. Because the combustion of biogas in a flare was selected as BACT for all other NSR pollutants, there was no consideration of other combustion controls performed in this analysis. The following control options have been identified and considered in determining BACT:

1. Installation of a flare. There are no effective combustion controls to reduce the GHG emissions from flares, and there are currently no available post-combustion controls. The only achievable technological approach to reducing GHG emissions from the flare is to use the most efficient flare that meets the final design requirements.

2. Develop and implementation of an LDAR program, similar to NSPS, Subpart VVa (40 CFR §60.480a through §60.489a), and modified to be source- and pollutant-type specific.

C. Eliminate Technically Infeasible Control Options

There were two (2) options identified for control of CO_2 emissions from the flare: 1) low-carbon fuel; and 2) energy efficient design. These control options are technically feasible for the flare and are an inherent part of the facility's design.

The following discusses each of these control options.

1. Fuel Type Restriction (Low-Carbon Fuel)

   The biogas flare will combust biogas as the primary fuel and natural gas in the pilot. Biogas has the lowest direct GHG emissions of all common fuels.[30] Natural gas is defined as a "clean fuel" under the CAA.[31] Natural gas has the lowest direct GHG emissions of all common fuels, excluding biogas. Carbon dioxide is a common impurity in natural gas which must be removed by the supplier to improve the heating value of the gas or to meet pipeline specifications. It is expected that natural gas utilized at the facility would not

[30] *General Reporting Protocol, Version 3.1*, supra note 39.
[31] Supra note 38.

benefit significantly from additional pre-combustion CO_2 removal activities such as membrane or cryogenic separation. Therefore, no further analysis of natural gas treatment options will be performed.

2. Energy Efficient Design

   There are numerous strategies for achieving a highly energy efficient design of a new flare. Design of the flare is dependent on the final process design of the facility. Specifically, the flare will be equipped with an electric igniter, will be a smoke-less design.

D. Rank Technically Feasible Options

The only achievable technological approach to reducing GHG emissions from the flare is to use the most efficient flare that can perform to the specification required by the facility's process. There is no effective combustion or post-combustion controls to reduce the GHG emissions from the 51.10 MMBtu/hr flare.

As there are no other control technologies to choose from, no additional steps in the top-down BACT analysis are required for the selection of these control technologies as BACT.

E. Establish BACT

ABBK proposes that GHG BACT for the flare consist of the following:

1. Use of lower GHG-emitting processes and practices through an energy-efficient design, incorporating a fuel efficient flare pilot; and

2. Develop and implement a written LDAR program.

ABBK proposes that the process vents flow, biogas flow and product loadout vapors will be inferred based on flow measurements upstream of the flare diverting valve and diverting valve position. ABBK further proposes that the pilot natural gas usage records be based on the vendor engineering calculations for the pilot's natural gas demand. No additional natural gas monitoring at the flare is proposed.

These control options are technically feasible for the flare and are an inherent part of the facility's design

The proposed BACT limit is 10,170 pounds CO_2e per hour (20,166 short tons CO_2e per year on a 12 month rolling average).

The facility will demonstrate compliance with the BACT limit by recording fuel usage and using the emissions factors approved by KDHE to determine resulting CO_2e emissions.

V. <u>Firewater Pump GHG BACT Analysis</u>

A. Source Description

One (1) 460 horsepower (hp) (343 kilowatt (kW)) firewater pump engine will be installed at the facility to protect personnel and equipment in the event of a fire. The firewater pump engine will combust diesel fuel and meet the New Source Performance Standard (NSPS) regulation, 40 CFR Part 60, Subpart IIII, *Standards of Performance for Stationary Compression Ignition (CI) Internal Combustion Engines (ICEs).* The emergency engine is assumed to operate less than 100 hours per year for maintenance checks and readiness testing to qualify as emergency engines under NSPS Subpart IIII (40 CFR §60.4211(e)).

The emergency diesel firewater pump engine will have the PTE of biogenic and anthropogenic GHG emissions (CO_2, CH_4, and N_2O) because it combusts a hydrocarbon fuel (diesel).

B. Identify Available Control Options

There are no effective combustion controls to reduce the GHG emissions from internal combustion engines, and there are currently no available post-combustion controls. The only achievable technological approach to reducing GHG emissions from the firewater pump engine is to use the most efficient engine that meets the stringent National Fire Protection Association (NFPA) standards for reserve horsepower capacity, engine cranking systems, engine cooling systems, fuel type's instrumentation and control and exhaust systems.

C. Eliminate Technically Infeasible Control Options

The only achievable technological approach to reduce GHG emissions from the firewater pump engine is to select the most fuel-efficient NFPA-20 certified firewater pump engine available.

As there is only one control technology to choose from, no additional steps in the top-down BACT analysis are required for the selection of that control technology.

D. Establish BACT

The firewater pump engine to be selected for use at the facility will be the most fuel-efficient NFPA-20 certified firewater pump engine available. The specific make and model has not been established; however, a review of similar sized engines has indicated that a fuel consumption rate of no more than 20.3±5% gallons per hour is the most efficient rating available for a 460 Hp engine with a rated speed of 1760 rpm and an EPA Tier 3 emission rating.

The firewater pump engine may be used for up to 100 hours per year for reliability testing and maintenance purposes. Use of the engine at 20.3±5% gallons of diesel fuel per hour for up to 100 hours per year would result in total GHG emissions of 480 pounds CO_2e per hour (24.0 tons CO_2e on a 12 month rolling average). ABBK requests that the fuel consumption GHG BACT limit include a 5% variability to allow for selection of the engine with lowest overall EPA Tier 3 emissions at the time of purchased.

The facility will demonstrate compliance with the BACT limit by recording fuel usage and using the emissions factors approved by KDHE to determine resulting CO_2e emissions.